Decision **PROPOSED DECISION OF COMMISSIONER RECHTSCHAFFEN**
(Mailed 10/4/2019)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan for Energy Utilities.	Rulemaking 13-11-006

DECISION MODIFYING THE COMMISSION'S RATE CASE PLAN FOR ENERGY UTILITIES

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Appendix A: Adopted Revised GRC Application Filing Schedule, Effective March 1, 2020

DECISION MODIFYING THE COMMISSION'S RATE CASE PLAN FOR ENERGY UTILITIES

Summary

The Commission manages its General Rate Case (GRC) proceedings for the large energy utilities subject to its jurisdiction in accordance with a "rate case plan" (RCP) that sets the schedule for each milestone in the proceeding.[1] The purpose of the RCP is to ensure that complex and financially significant GRC proceedings follow a predictable schedule that balances the need for timely Commission decisions with procedural fairness for all parties. In this decision we review and address proposals regarding how we could conduct GRC proceedings more efficiently, and whether we should extend the GRC cycle for each utility from three years to four years. We adopt the following:

- The current three-year GRC cycle is changed to a four-year cycle, beginning with PG&E's Risk Assessment and Mitigation Phase (RAMP) filing in March 2020 followed by its GRC application to be filed in 2021.
- The generic GRC proceeding schedule adopted in Decision 14-12-025 is modified as follows:
    - The filing date for GRC applications is moved from September 1 of the year that is two years prior to the applicant's test year, to March 1 of that year;
    - Additional time is provided to the Commission's independent Public Advocates Office to complete its comprehensive review of the utilities' application and serve its testimony; and
    - PG&E shall combine its currently-separate GRC and Gas Transmission and Storage rate cases into a single rate case

[1] The large energy utilities required to follow this schedule are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E).

application beginning with its 2020 RAMP filing and the GRC application due to be filed in 2021 for its 2023 test year.

- A workshop or workshops will be facilitated by the Commission's Energy Division to further explore and develop proposals regarding
  - o Standardizing the organization and format of GRC and RAMP filings;
  - o The possible use of stipulated terms and rebuttable presumptions to reduce litigated issues, and improving the accuracy of attrition year forecasting, escalation factors, and ratemaking; and
  - o High level consistency in the Results of Operations modeling process across utilities.

This proceeding is closed.

1. Background

This decision concerns "Phase 1" of the General Rate Case (GRC) proceedings for the investor-owned large energy utilities, where the Commission reviews and authorizes the revenue requirement necessary for the utility to recover the reasonable capital investment costs and annual expenses necessary to operate and maintain its facilities and equipment, in a safe and reliable manner. The Commission conducts these proceedings according to a standard "rate case plan" and schedule (RCP) that requires each utility to file a GRC application with the Commission every three years. In a later and separately-filed "Phase 2" of a GRC, the Commission addresses proposals regarding how the revenue requirement that it authorized in Phase 1 should be allocated among customer classes, and collected from those customers in rates.[2]

[2] For natural gas utilities, the allocation issues are addressed in subsequent cost allocation proceedings, rather than a second phase of their GRC.

The Commission opened this rulemaking in 2013 out of concern that the energy utilities were not explicitly or adequately addressing safety and reliability issues in their GRC funding requests. The Commission determined that the assigned Commissioner and Administrative Law Judge (ALJ) in GRC proceedings would be better equipped to guide the proceeding from its inception if the RCP required the applicant utility to include an appropriate showing on safety and reliability issues in its application. Thus, the primary purpose of this rulemaking was to determine whether and how to formalize rules to ensure the effective use by large electric and gas utilities of a "risk-based decision-making framework" to evaluate the safety and reliability improvements requested in their GRC applications.[3] However, the Commission also articulated a second purpose for the rulemaking: "in conjunction with this focused review on safety, security and reliability issues, we may also consider broader revisions in the RCP in more general terms to promote more efficient and effective management of the overall rate case process."[4]

Following a public workshop and several rounds of comments by parties to the rulemaking, the Commission adopted Decision (D.) 14-12-025, its "Decision Incorporating a Risk-Based Decision-Making Framework into the Rate Case Plan." The Commission adopted a risk-based decision-making framework consisting of a Safety Model Assessment Proceeding (S-MAP), a Risk Assessment and Mitigation Phase (RAMP) proceeding, and the filing of annual post-GRC verification reports consisting of a Risk Mitigation Accountability Report and a

[3] Rulemaking (R.) 13-11-006 at 1.

[4] *Id.*, at 6.

Risk Spending Accountability Report.[5] The Commission also modified the RCP in order to accommodate the newly created proceedings.[6] In making these modifications, however, the Commission denied requests of some parties to expand the standard three-year GRC cycle to a four-year cycle.[7]

In September 2015, several parties filed a joint petition for modification (PFM) of D.14-12-025, again requesting that the standard length of the GRC cycle be extended from three years to four years.[8] The petitioners contended that moving to a four-year GRC cycle would allow better use of both utility and Commission resources, and facilitate the timely completion of the newly created proceedings implementing the risk-based decision-making framework, as well as the GRC proceedings themselves.

The Commission denied the PFM in D.16-06-005, explaining that (as of June 2016) extending the GRC cycle by an additional year would delay incorporation of the RAMP process into future GRC filings of the energy utilities. The Commission also found that the joint parties were renewing arguments that the Commission had already considered and rejected in D.14-12-025. However, the Commission also stated in D.16-06-005 that "we think it is appropriate to explore the GRC cycle length further in the context of timely processing all of the

[5] D.14-12-025, Ordering Paragraph 1.

[6] *Id.*, Ordering Paragraph 2.

[7] *Id.*, at 40: "On the three-or four-year GRC cycle, we will retain the three-year cycle. The three year cycle will minimize overlapping GRCs so long as the RCP schedule is followed. We recognize, however, that there are oftentimes other circumstances or events that interfere with the timely proceeding of GRCs. The assigned Commissioner and ALJ shall have the discretion to alter the schedule as may be needed. Should the S-MAP, RAMP, and GRC processes pose scheduling conflicts, we may need to revisit the need for a four-year rate cycle."

[8] Joint Petition of SDG&E, SoCalGas and Office of Ratepayer Advocates (Public Advocates Office) for Modification of General Rate Case Cycle Length in Decision 14-12-025, at 7.

recurring major rate-related proceedings, such as the GRCs, cost allocation proceedings, and PG&E's gas transmission and storage proceeding, in addition to the added processes of the S-MAP and RAMP."[9] The Commission directed the Commission's Energy Division to conduct a workshop to address the issues that are involved in moving to a longer GRC cycle, and to prepare a workshop report on whether a longer GRC cycle is worth pursuing.[10] This rulemaking proceeding has remained open to consider the results of the workshop and other miscellaneous changes to the RCP.[11]

The Energy Division conducted its workshop on January 11, 2017 and completed its workshop report in March 2018. On March 8, 2018 the assigned ALJ issued a ruling that provided the Energy Division's "General Rate Case Plan Workshop Report" (Staff Report) to the service list, accepted the report into the proceeding record, and set a schedule for comments and reply comments on the recommendations made in the Staff Report.

The parties listed below filed and served comments on April 5, 2018:

- Pacific Gas and Electric Company (PG&E);
- Southern California Edison Company (SCE);
- Southern California Gas Company and San Diego Gas & Electric Company (jointly, as SDG&E and SoCalGas);
- the Commission's independent Office of Ratepayer Advocates (hereinafter, the Public Advocates Office);[12]

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[9] D.16-06-005 at 6.

[10] *Id.*, Ordering Paragraph 2.

[11] *Id.*, Ordering Paragraph 3.

[12] In 2018 the Office of Ratepayer Advocates (ORA) was renamed the Public Advocates Office of the Public Utilities Commission pursuant to Senate Bill 854 (Stats. 2018, ch. 51). Although all the pleadings in this proceeding were submitted under the name of ORA, this decision updates those references to the Public Advocates Office in order to avoid confusing readers.

- the Southern California Generation Coalition (SCGC); and
- The Utility Reform Network (TURN).

SCE and TURN filed and served reply comments on April 19, 2018.

The Staff Report and parties' comments and reply comments on that report constitute the record that serves as the basis for this decision.

2. The Commission's Rate Case Plan for Energy Utilities

As noted above and explained in the Staff Report, a GRC is a proceeding in which the Commission authorizes an investor-owned utility to recover through rates the reasonable capital investment costs and annual expenses necessary to operate and maintain its facilities and equipment in a safe and reliable manner. The large energy utilities are required to file a GRC application every three years with the Commission. This filing period is known as the three-year GRC rate case cycle. The GRC application provides detailed forecasts of capital investment and operating and maintenance (O&M) expenses for a designated "test year" as well as forecasts for two subsequent post-test years, or "attrition years." The Commission's decision is based on an extensive review of the test year forecasts, while the post-test year revenue requirements are typically determined by (1) escalating the test year O&M expenses, and (2) authorizing capital expenditures at a level determined by either (i) additional escalation factors, or (ii) further review of the applicant utility's capital budgets for those years.

For all its procedural and technical complexity, the Commission's decision in a GRC proceeding can be summarized on a single page, the "Summary of Earnings" authorized for the applicant utility in the test year. This consists of (1) the annual O&M expenses approved by the Commission, plus (2) the revenues the utility may collect to recover the costs of its capital investments for the test year, and (3) the utility's estimated tax obligations. The capital-related revenues are expressed indirectly as the sum of (i) return on the utility's rate base, and (ii) the depreciation expense associated with the capital assets in the rate base. The table below depicts a typical Summary of Earnings statement:[13]

<u>Annual Summary of Earnings</u>

	Authorized O&M Expenses
plus	Return on Rate Base
plus	Taxes
plus	Depreciation Expense
equals:	Annual Customer Revenue Requirement

Procedurally, a typical GRC proceeding at the CPUC unfolds in the manner described in the quote below:

> Required revenues and the rates necessary to realize them are established via the rate case, which is a quasi-judicial procedure designed to provide due process to all affected parties (e.g., the utility, investors, customers) and produce rates which are just and reasonable. As part of the rate case process, regulators evaluate the prudency (i.e., recoverability) of costs after they are incurred.[14]

The economic literature also discusses the need for timely and predictable Commission action on GRCs and related issues:

> Once the revenue requirement is established, the rates are applied to the real time, real world market place where a set of dynamic factors, including demand growth, inflation, and government mandates determines the actual cash flows and earnings of the utility. To the extent that the real world approximates the

[13] As will be seen below, the utilities calculate the Summary of Earnings using a "Results of Operations" (RO) model; at times the two terms are used interchangeably.

[14] Edison Electric Institute, "Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation," prepared by Dr. Karl McDermott, at viii and 12.

> assumptions used to establish the total revenue requirements, the cost-of-service model can operate effectively with regulatory lag serving as an incentive to control costs. However, if technical, economic, and financial shocks negate these assumed conditions, regulators have been required to search for pragmatic policy adjustments in order to re-establish the balance of interests.[15]

Regular participants in GRC proceedings at the CPUC will certainly recognize that the GRC proceedings of the large energy utilities reflect both the necessity of regulation, and the challenges inherent in this form of government oversight.

Referring again to the economic literature, the general rate case proceeding is viewed as the embodiment of what is often described as the "regulatory compact." This compact is viewed as a contract between the utility's investors and its customers; as such, it establishes rights, obligations, and benefits for both sides of the bargain.

- Utilities accept the obligation to serve and charge regulated cost-based rates, and customers accept limited entry (i.e., loss of choice) in exchange for protection from monopoly pricing.
- Under this agreement, the utility is provided the opportunity to recover its actual legitimate or prudent costs—determined by a public examination of the utility's outlays—plus a fair return on capital investment as measured by the cost of obtaining capital in a competitive capital market.
    - Investors will only provide capital for provision of utility services if they anticipate obtaining a return that is consistent with returns they might expect from employing their capital in an alternative use with similar risk;
    - Customers will only accept utility rates if they perceive that the rates fairly compensate the utility for its costs, but

[15] *Id.* at viii.

> are not excessive as a result of the utility taking advantage of its privileged position.[16]

It is the role of regulatory bodies such as this Commission to ensure that both sides fulfill their respective obligations under this bargain. Given the vastly different resources at the disposal of each side, it is up to the Commission to maintain the balance in outcomes between customers and shareholders. This somewhat theoretical construct becomes very real when the Commission fulfills its responsibility and quantifies this balanced outcome in its decisions in general rate cases.

Our brief summary of the regulatory compact does not reveal anything that is not already well-understood by the utilities and intervenors in GRC proceedings. However, in light of a number of extraordinary catastrophic events involving California's regulated energy utilities in recent years (e.g., the 2010 San Bruno pipeline explosion in PG&E's territory and the major wildfires in 2007, 2017 and 2018 in SDG&E, PG&E and SCE territories) a review of first principles may be in order. As the utilities consider and implement corrective measures after these events, the forum for Commission review and authorization of the related capital investment costs and operating expenses is, either directly or indirectly, each utility's GRC proceeding. As such, both investors and utility customers can reference over a century of legal and regulatory history that confirms the Commission's role is not to merely pass utility cost estimates on to ratepayers, but rather to first determine the level that represents the just and reasonable costs for the utility to meet its obligations.

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[16] *Id.* at 6.

The authority of state regulatory commissions dates back to 1877, when the U.S. Supreme Court upheld the power of government to regulate private industries by recognizing that certain economic activities were so critical to the functioning of a modern society that government has the right to oversee the prices charged to assure that such services are provided to the public in a reasonable manner.[17] The *Munn* decision was limited by subsequent Court decisions, though not its broad application to state regulation of public utilities. However, it was not until 1944 that the Court articulated the notion that some sort of bargain offers guidance to regulators, though this principal continues to guide every rate case: in its *Hope* decision, the Court stated that the regulatory process involved a balancing of customer and stockholder interests:

> [t]he rate-making process ... i.e., the fixing of just and reasonable rates, involves a balancing of the investor and the consumer interest.[18]

We find it important to restate this principal in order to remind parties that the *benefits* of the regulatory compact come with corresponding *obligations*. In the remainder of this section we briefly review how the CPUC came to interpret the terms of the regulatory compact.

The Commission has managed large energy utility GRC proceedings in accordance with some form of "rate case plan" since 1977, when it adopted its first "Regulatory Lag Plan for Major Utility General Rate Cases" (RLP).[19] As the

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[17] *Munn v. Illinois*, 94 U.S. 113, 146 (1877).

[18] *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591 (1944), at 603.

[19] Resolution A-4693, July 6, 1977. In 1982, the Commission revised the RLP and renamed it the "Rate Case Processing Plan" (RCPP). *See*, Resolution ALJ-149, October 20, 1982. Perhaps reasoning that its handiwork can always be further improved, the Commission declared two months later that "the name of the RCPP is too lengthy and should be changed to Rate Case Plan (RCP)." *See*, D.82-12-072 at 2.

title of the RLP indicates, the Commission has always recognized the challenges created by "regulatory lag." In 1997 the Commission summed up the intervening 20 years and succinctly articulated the purpose of such plans:

> With regulatory lag i.e., the delay between seeking and obtaining relief from the Commission confronting our regulatory process, we adopted a Regulatory Lag Plan … on July 6, 1977. The experience gained from processing general rate changes under the RLP enabled us to consider modifications that would make the RLP more workable and *further minimize regulatory delay while providing an administrative forum with fairness to all*.[20]

Notably, in the text quoted above the Commission expressed its dual goals as minimizing regulatory delay without sacrificing fairness for all parties. As we discuss further below, an important result when the Commission achieves these goals is that all stakeholders, most notably the utilities' investors and customers, can rely on the Commission to process GRCs in a manner that produces predictable results.

The Commission has also modified the RCP over the years to incorporate legislative directives. In 1951 the passage of the Public Utilities Act established the Public Utilities Code (Pub. Util. Code) in its modern form. At that time, Pub. Util. Code § 311 (hereinafter, section 311) was limited to defining the

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[20] R.97-06-038, "Order Instituting Rulemaking on the Commission's Own Motion into the Establishment of a Rate Case Plan for Small Local Exchange Carriers" at 2. Emphasis added.

We note that the economic literature distinguishes between two types of "regulatory delay" or "lag": (1) the lag <u>between</u> rate cases, and (2) the lag <u>during</u> the pendency of a rate case. Over the years, the CPUC has established ratemaking mechanisms that reduce the risk that the lag between rate cases will result in utility revenues not matching forecast costs. For the second type of lag, which this Commission terms "regulatory lag," the literature notes that it "can cause gaps in the ability of utilities to recover prudently incurred costs or, depending on the circumstances, may cause costs in the test year to be overstated." *See*, Edison Electric Institute, "Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation," prepared by Dr. Karl McDermott, at 15-16.

powers of the Commissioners and "examiners" to administer oaths, examine witnesses, issue subpoenas, and receive evidence.[21] Since that time, the Legislature periodically amended and expanded section 311 in ways that required the Commission to update the RCP to remain consistent with the express intent of the Legislature. In 1982 the Legislature amended section 311 to define the role of ALJs in more detail, introducing the requirement that "[t]he proposed decision of the administrative law judge shall be filed with the commission and served upon all parties to the commission without undue delay but in no event later than 90 days after the matter has been submitted for decision."[22] Notably, the same amendment clarified that

> [i]t is the intent of the Legislature that the implementation of this act shall not require extension of the time period currently required for the Public Utilities Commission to act on any matter before it, and that the schedule for acting on rate increase applications by the commission, as specified in the commission's Regulatory Lag Plan for Major Utility General Rate Cases…shall not be changed by the provisions of this act.[23]

The Commission again found it necessary to revise the RCP after the Legislature further amended section 311 in 1986 to require that, after the issuance of the ALJ's proposed decision, the Commission shall issue its own final decision not sooner than 30 days following that date.[24] The 1986 amendments led the Commission to initiate R.87-11-012, its "Order Instituting Rulemaking to Revise the Time Schedules for the Rate Case Plan and Fuel Offset Proceedings." The

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[21] Stats 1951, ch. 764. In 1979 section 311 was amended to refer to "administrative law judge" instead of "examiners."

[22] Stats. 1982, ch. 1542.

[23] *Ibid.*

[24] Stats. 1986, ch. 893.

Commission's list of tasks for R.87-11-012 indicate its continuing focus on timeliness and procedural fairness:

1. reflect the requirements of § 311 in the processing of general rate cases and energy offset proceedings;
2. develop reasonable time schedules for processing general rate cases and energy offset proceedings; and
3. consider changes to general rate cases that could ease the burden of issuing year-end decisions.[25]

The Commission proceeded to adopt a number of major changes to the RCP in D.89-01-040, each of which is reflected in the current RCP. First, the Commission established a generic annual cost of capital proceeding for energy utilities, to remove that workload from GRCs. Second, the Commission moved electric rate design issues to a newly created Phase 2 proceeding; in subsequent decisions the Commission moved the related issues of marginal costs and cost allocation to Phase 2 as well. The Commission also specified in D.89-01-040 that cost allocation and rate design for gas utilities would be addressed in separate Annual Cost Allocation Proceedings (ACAPs, which more recently have taken the form of biennial, triennial, or simply "gas cost allocation proceedings, i.e., GCAPs). Finally, the Commission established new and separate proceedings for the reasonableness reviews of the electric utilities' energy procurement.[26]

The streamlined RCP framework adopted in D.89-01-040 remained essentially unchanged for the next 25 years, but its significant procedural modifications and narrowing of scope for Phase 1 proceedings did not result in

[25] D.89-01-040 in R.87-11-012, at 2.

[26] For PG&E, SCE and SDG&E that proceeding has become the Energy Resource Recovery Account (ERRA) compliance review, not a reasonableness review. For PacifiCorp and Liberty Utilities, that proceeding is the Energy Cost Adjustment Clause (ECAC).

dramatic improvements in the timely processing of the now-streamlined GRC proceedings. Indeed, although the instant rulemaking focused on developing the S-MAP and RAMP, the Preliminary Scoping Memo included in the Rulemaking invited parties to submit comments on six sets of questions, four of which addressed procedural aspects of the GRC process itself:

1. Process to provide appropriate analysis and testimony on safety and risk management;
2. Comprehensive review of safety, reliability, security, and risk management in the utilities' GRC applications;
3. Timing of the GRC applications;
4. RCP schedule;
5. Uniform application of the provisions of the RCP; and
6. Reducing complexity.[27]

Regarding questions #3 through #6 listed above, parties initially discussed whether elements of the RCP should be modified to promote more efficient and effective management of GRCs in their January 2014 comments on the Rulemaking. Next, pursuant to the May 15, 2014 Scoping Memo, parties filed and served comments and reply comments on the RCP issues on July 25 and August 22, 2014, respectively.

Consistent with the approach established in the Scoping Memo, the Commission approved its risk-based decision-making framework to evaluate safety and reliability improvements in D.14-12-025. To the extent necessary to accommodate this new framework, the Commission also modified and replaced

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[27] R.13-11-006 at 10-16. In addition, the May 15, 2014 Scoping Memo determined that a first round of comments would provide the record for a Commission decision addressing questions #1 and #2 regarding the risk-based decision-making framework, while a second round of comments would provide the record for a subsequent Commission decision addressing questions #3 through #6 regarding possible revisions to the RCP.

the RCP schedule adopted in Appendix A of D.07-07-004.[28] However, the Commission also noted that a second phase, and a separate decision, would address proposals to revise the RCP to promote more efficient and effective management of the overall rate case process.[29] As noted above, in D.16-06-005 the Commission established the workshop process that led to the Staff Report and parties' associated recommendations that we address in today's decision.

The current RCP is provided in Table 4 of D.14-12-025 (GRC Application Filing), and reproduced on the following page.

[28] D.14-12-025, Ordering Paragraph 2.

[29] D.14-12-025 at 9, citing the May 15, 2014 Scoping Memo at 6.

Table 1
Decision 14-12-025
Current GRC Application Filing Schedule[30]

Date	Day #	Event
Test Year minus-3		
September 1		Utility requests initiation of RAMP proceeding
By November 15		RAMP Order Instituting Investigation (OII) is opened
By November 30		Utility files its RAMP submission in the OII
Test Year minus-2		
September 1	0	Utility files GRC application, and serves prepared testimony
30 days after Daily Calendar notice		Due date for protests and responses to GRC application, pursuant to Rule 2.6(a)[31]
By October 15	44	Utility holds public workshop on overall GRC application
By October 31	60	Prehearing Conference held
	90	Scoping Memo of Assigned Commissioner issued
Test Year minus-1		
By February 20	172	Public Advocates Office serves opening testimony
By March 17	197	Intervenors serve opening testimony
May 1	242	Concurrent rebuttal testimony served
March/April		Public Participation Hearings
May/June	270	Evidentiary hearings begin, if needed
	289	Evidentiary hearings end
May/June		Update testimony and hearings, if necessary
To be decided	324	Briefs filed
To be decided	345	Reply briefs filed, proceeding submitted for Commission decision
September/October	425	Proposed decision issued
November	455	Final decision adopted
Test Year		
January 1	487	Effective date

30 D.14-12-025, at 42 (Table 4). For further clarity, we have added the column labeled "Day #" to indicate the time that passes between various milestones. This information was included in earlier versions of the RCP.

31 All references to "Rules" in this decision are to the Commission's Rules of Practice and Procedure.

As will be seen below, some of the changes to the RCP schedule adopted in D.14-12-025 have proven to be overly optimistic, or unrealistic. For example, the schedule assumes the proceeding will be concluded in 16 months, even though Pub. Util. Code Code § 1701.5 (a) provided for 18 months from the date the scoping memo was issued in the proceeding.[32] The Commission also shortened the deadline for the Public Advocates Office to serve its testimony by 2 months, which has proven to be unreasonable for development of a comprehensive record.

These are among the issues we address in today's decision.

3. The Energy Division Workshop

The Energy Division staff organized the workshop agenda and discussions to focus on the primary questions of how to process GRCs more efficiently and whether to extend the standard GRC cycle to four years. Staff provided parties with discussion questions prior to the workshop, so that participants were prepared to discuss these issues in depth.

The morning session of the workshop addressed the topic of "facilitating the timely completion of GRCs." Staff posed the following questions to participants prior to the workshop to stimulate discussions on these topics:

1. Does the current RCP schedule allow sufficient time for the utilities, all intervening parties, and Commission staff to process GRC proceedings in a timely manner? If not, why not?
2. Are there ways to reduce the complexity of GRC proceedings and streamline GRC filings? What are they?
3. What are other areas needing improvement within the current RCP?

[32] Section 1701.5 was amended in 2016 to modify the term "scoping memo is issued" to "proceeding is initiated" which had the effect of shortening the prior statutorily-allowed timeline by 2 or 3 months.

4. Are there things the utilities or parties can do to assist the Commission to review GRC filings more efficiently? If so, what are they?[33]

The Energy Division invited a panel of speakers to address these questions, consisting of representatives from the Commission's Safety Enforcement Division (SED), SDG&E and SoCalGas, PG&E, Public Advocates Office, and TURN. Participants discussed the challenges that have impeded the Commission from resolving GRC proceedings according to the RCP schedule and possible ways to help the Commission process GRC proceedings more efficiently.[34]

The afternoon session of the workshop addressed the topic of "the pros and cons of a three-year versus four-year GRC cycle." Staff again posed a number of questions to participants prior to the workshop:

1. Does a four-year GRC cycle relieve constrained resources issues (Commission staff – ALJ, ED, SED, Public Advocates Office, and parties)? What resources would be freed up with the four-year cycle that are currently constrained by the three-year cycle?
2. What processes and/or procedures are improved with a four-year GRC cycle? What other benefits does a four-year GRC cycle bring?
3. What issues does a four-year cycle create that would not occur in a three-year cycle?
4. Why should the Commission pursue or not pursue a four-year GRC cycle? What assurances are there that a four-year cycle wouldn't suffer the same delays as the three-year cycle?[35]

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[33] *Ibid.*

[34] Staff Report at 6.

[35] *Ibid.*

Panelists from the Sempra Utilities (SDG&E and SoCalGas), PG&E, Public Advocates Office, and TURN were invited to speak to the challenges of a three-year rate case cycle versus a four-year rate case cycle.[36]

4. Energy Division Recommendations

The Energy Division's post-workshop Staff Report included a detailed review and discussion of parties' presentations and positions (Appendix A of the Staff Report provides links to parties' workshop presentations, which are posted on the Commission's website). The Staff Report concluded with the following recommendations:

1. The Commission should retain the current three-year GRC cycle, because its drawbacks are outweighed by challenges created by moving to a four-year cycle.
2. The Commission should direct PG&E to combine its gas transmission and storage (GT&S) and GRC proceedings, because a single proceeding would provide the Commission with the best overall picture of PG&E's operations.
3. The Commission should modify the Rate Case Plan to move the submittal date for the Public Advocates Office's opening testimony from the current February date to April, because the additional time is necessary for the Public Advocates Office to prepare the comprehensive testimony that the Commission requires for its decision-making.
4. In order to improve the efficiency of GRC proceedings, Energy Division should host additional workshops to address the following topics:
   i) Broader standardization of GRC filings across the utilities;
   ii) The feasibility for the Commission to adopt stipulated terms or rebuttable presumptions in order to reduce litigated issues;

[36] Staff Report at 21.

iii) Results of Operations (RO) model uniformity; and

iv) The feasibility of utilities submitting their GRC requests using the standard FERC system of accounts.

5. The Commission should open a rulemaking to revisit its policies on the utilities' recovery of income tax expenses and related ratebase issues.

As noted above, parties were invited to submit comments and reply comments on those recommendations. We turn to our discussion of parties' recommendations below.

5. Discussion

At the outset of our discussion, it is important to be clear about what we are trying to accomplish with any modifications to the RCP that we adopt in this decision. Our goals must also account for the statutory requirements described above, as well as others that apply to ratesetting proceedings such as GRCs.[37]

First, we should change the RCP if it will improve our ability to meet our obligations under the Public Utilities Code. Pub. Util. Code § 451 requires us to ensure that utility rates are "just and reasonable." Pub. Util. Code § 1701.3 requires that our decisions on utility GRC applications be "based on evidence in the record."[38] If not, our decisions may be annulled if a reviewing court finds they are not supported by the findings, or are not supported by substantial evidence in light of the whole record.[39] Procedurally, the Commission must

[37] As noted above, in D.14-12-025 the Commission recognized that "there are oftentimes other circumstances or events that interfere with the timely proceeding of GRCs." D.14-12-025 at 40. Nevertheless, our purpose in this decision is to revise the RCP plan and schedule so that, absent intervening circumstances, the proceeding can meet the expectations of the applicants and intervenors.

[38] Pub. Util. Code § 1701.3 (j).

[39] Pub. Util. Code § 1757 (a)(3) and (a)(4).

complete GRC proceedings within 18 months of the initiation of the proceeding (i.e., the date the utility files its application).[40] Within the specified time frame, Pub. Util. Code § 311(d) requires that the proposed decision of the assigned ALJ or the assigned commissioner shall be issued not later than 90 days after the matter has been submitted for decision and the Commission shall not issue its decision sooner than 30 days following issuance of the proposed decision.[41]

Second, our review of the Staff Report and parties' comments indicate that we should change the RCP if we can better satisfy the "must-haves" expressed by the utilities, the Public Advocates Office, and the other parties that routinely intervene in GRC proceedings. Those priorities affect our options regarding modifications to the RCP schedule in significant ways:

- The utilities want the Commission to issue a timely final decision adopting their revenue requirement in time to be implemented on January 1st of the test year;
- The Public Advocates Office requires sufficient time to conduct discovery and prepare its testimony, because its analysis and recommendations serve as a point of reference for the testimony served by other intervenors a month later;
- The other intervenors should also be provided with sufficient time after the Public Advocates Office serves its testimony, to complete their own discovery and prepare their testimony;
- Once all testimony has been served, all parties in the proceeding should have sufficient time to prepare their rebuttal testimony;

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[40] Pub. Util. Code § 1701.5 (a). However, the Commission may specify a later resolution date in the scoping memo for the proceeding; *see,* Pub. Util. Code § 1701.5 (b).

[41] Pursuant to Rule 13.14 (a) (Submission and Reopening of Record), a proceeding shall stand submitted for decision by the Commission after the taking of evidence, the filing of briefs, and the presentation of oral argument as may have been prescribed.

- After rebuttal testimony has been served, all parties should have sufficient time to prepare for evidentiary hearings, and to subsequently prepare post-hearing briefs and reply briefs; and
- Once the case is submitted, the assigned ALJ and Commission staff should have sufficient time to prepare the proposed decision, and to calculate the resulting Summary of Earnings and authorized annual revenue requirements using the RO model.

Our consideration of the challenges listed above is illuminated by our very recent experience in SCE's test year 2018 GRC proceeding (A.16-09-001). That case was a "typical" GRC in many ways because it closely tracked the RCP schedule mandated by D.14-12-025:

- SCE filed and served its GRC application on the September 1 due date;
- The schedule adopted in the scoping memo provided <u>almost</u> all the other "must-haves" listed above:
    - ORA received 2 extra months to prepare its testimony;
    - the intervals between other major procedural milestones were established as requested by parties;
    - based on the submittal date in the Scoping Memo, the proposed decision would be issued by the end of December 2017 for consideration by the Commission at a voting meeting 30 days later, i.e., approximately one month after the 2018 test year began.
- All the major issues in the case were fully litigated, rather than settled, so three weeks of evidentiary hearings were held, and voluminous briefs and reply briefs were filed and served by SCE, Public Advocates Office and other intervenors.

The proceeding tracked the schedule required by the RCP through the submittal date in September 2017. From that point onward, however, the Commission did not follow the RCP. In fact, the proposed decision of the two assigned ALJs was issued on April 12, <u>*2019*</u> (i.e., over 18 months after the submittal date). The Commission adopted the PD at its next meeting on May 16, 2019. In short, the applicant and the other parties met the requirements and deadlines of the RCP, but the Commission, collectively, did not.[42]

We consider a delay of this magnitude to be a one-time occurrence. Still, the long delay in issuing this particular PD was merely an extreme example of what parties consider to be typical in large GRC proceedings: the PD is rarely completed within the 90-day statutory deadline.

Based on our review of the history of the RCP at the Commission, related statutory requirements, and with the benefit of very recent hindsight regarding the SCE GRC, we nevertheless find that several relatively simple changes will address many of the challenges created by the current RCP schedule. Those scheduling changes, along with other procedural recommendations from the Staff Report or parties that we also adopt herein, should greatly improve our ability to produce timely GRC decisions based on a fair administrative hearing process, on a schedule that provides predictable outcomes for the utilities and the stakeholders in the regulatory compact: investors and customers.

To simplify the solution, we can begin with two "must-haves" and work backwards from those milestones to create a new RCP schedule. First, we should plan that the Commission will issue its final decision on December 1st of the year preceding the test year. This meets the utilities' stated must-have and provides them with 30 days to incorporate the Commission's decision into any rate change that takes effect on January 1st of the test year. Second, we should modify the RCP schedule to provide the Public Advocates Office with the time it has

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[42] For the purposes of this illustration, we acknowledge but ignore the fact that the proceeding also stayed open in order to address the passage in late 2017 of the Tax Cut and Jobs Act, because the proposed decision would have already been issued if the RCP had been followed.

consistently stated it requires to conduct discovery and prepare its testimony. With these two "must-haves" in place, we should also maintain the time gaps between other major proceeding milestones, as requested by other parties. Finally, a realistic period of time should be established for the ALJ or ALJs to draft the PD and oversee calculation of the resulting Summary of Earnings.

With the above scheduling milestones in mind, we find that if we modify the RCP schedule to require the utilities to file their GRC applications six months earlier, on March 1st instead of September 1st of "test-year minus-2" then the Public Advocates Office can be given a realistic amount of time to prepare its testimony, and the utilities can receive their decision prior to the start of their test year, all while preserving the other intervals between major milestones that parties have indicated are important to them.

The generic schedule in Table 2 below is the result of applying these criteria:

Table 2
Illustrative Generic GRC Schedule

Date	Day #	Milestone
Test Year minus-3		
March 1		Utility requests initiation of RAMP proceeding
By May 1		RAMP Order Instituting Investigation (OII) is opened
By May 15		Utility files its RAMP submission in the OII
Test Year minus-2		
March 1	0	Utility files GRC application and serves prepared testimony
October 10	223	Public Advocates Office serves opening testimony
November 5	249	Intervenors serve opening testimony
December 20	294	Concurrent rebuttal testimony served
Test Year minus-1		
January 15	320	Evidentiary Hearings Begin
February 2	338	Evidentiary Hearings End
March 10	375	Briefs filed
March 31	396	Reply briefs filed
November 1	521	Proposed decision mailed for comment
December 1	611	Final decision adopted
Test Year		
January 1	672	Effective date of final decision

These changes are deceptively simple. However, given the complexity of GRCs and the importance of adhering to a schedule that results in a final Commission decision by a predictable "date-certain" we note that the Commission must still support major GRC proceedings with adequate staff resources to ensure success. This begins at the ALJ level, but extends to the staff level in the industry divisions so that the ALJs and the Commissioners have sufficient analytical resources to support their decision-making. In fact, this expanded staffing is already occurring in the Commission's Energy Division and Safety and Enforcement Division so we need mainly to ensure that this trend continues and is sustained.

With this partially modified RCP schedule as our initial reference point, we turn next to the specific recommendations in the Staff Report, and determine how a modified schedule would or would not accommodate them.

5.1. Retention or Change of the Three-Year GRC Cycle

As we explained above, in D.16-06-005 the Commission indicated it wished to explore lengthening the GRC cycle further, "in the context of timely processing all of the recurring major rate-related proceedings, such as the GRCs, cost allocation proceedings, and PG&E's gas transmission and storage proceeding, in addition to the added processes of the S-MAP and RAMP."[43]

In our view, parties at times conflate two distinct issues to contend that (1) the Commission would find it easier to complete GRCs "on time" if (2) the GRC cycle was lengthened from three years to four years. We disagree with this formulation. In order to issue a GRC decision prior to the test year, the Commission, the ALJs and the staff must process a large amount of information and accurately calculate a large revenue requirement in a short period of time. Given the complexity of large energy GRCs, in practical terms it will remain difficult to prepare the draft decision within the 90-day statutory deadline following submittal of the proceeding, regardless of whether the GRC cycle is three or four years. That said, although we do not consider a four-year GRC cycle as *the* solution to the need for timely decisions, parties offered other reasons for lengthening the GRC cycle, and we consider those now.

At the outset, we note the Staff Report recommends the Commission retain a three-year GRC cycle at this time.[44] Staff acknowledges the drawbacks of a

[43] D.16-06-005 at 6.

[44] Staff Report at 28, Section 7.4.

three-year cycle (primarily related to the relative burden placed on resources of the applicant, the intervenors, and the Commission), but suggests these drawbacks are outweighed by the potential problems that could come with a longer GRC cycle, such as:

- Increased uncertainty regarding forecast expenditures for the third attrition year;
- Greater reliance on the accuracy of post-test year ratemaking mechanisms;
- Concerns that attrition year revenue requirements tend to be higher than test year revenue requirements (perhaps due to less scrutiny of the attrition year forecasts); and
- It may be more difficult for the Commission to address emergent issues during the three attrition years, particularly given the rapid changes currently occurring in the electric sector (e.g., expected increases in distributed energy resources and, most recently, increased wildfire-related costs).[45]

Staff tempers its recommendation to retain a three-year cycle by noting workshop participants seemed most concerned that a four-year GRC cycle would result in greater uncertainty about attrition year forecasts and post-test year ratemaking. Staff thus recommends the Commission reconsider the merits of a four-year GRC cycle if the Commission receives input from future workshops that addresses these concerns:

> If the Commission were able to establish a <u>uniform and consistent</u> attrition year ratemaking mechanism that would factor in uncertainties during the attrition years, <u>the risks of inaccurate cost forecasts associated with an additional attrition year</u> would be mitigated.[46]

[45] *Ibid.*

[46] *Ibid*, emphasis added.

Retention of the current three-year cycle is supported in the comments and/or reply comments of SCE, SCGC and TURN. SCGC states its agreement with Staff's framing of the potential problems of a four-year cycle (summarized above) and adds that it is unclear to SCGC how standardizing attrition year ratemaking would address Staff's concerns: "standardization would not address the uncertainty that is inherit in forecasting an additional year of attrition year experience, and standardization would not address issues that may emerge during the attrition period."[47] TURN also concurs with Staff's recommendations and supporting analysis,[48] while also endorsing Staff's recommendation that a workshop process further explore a third attrition year while "retaining the three-year GRC cycle in the meantime."[49] SCE does not oppose a four-year cycle "outright" but contends that a change to a four-year cycle must (1) include an attrition year mechanism that provides the funding necessary for safe and reliable service, and does not lead to shortfalls in authorized spending; (2) incorporate "[a] greater tolerance on the part of the Commission and parties with respect to errors and variances in forecasting;" and (3) consider the necessity of using a Z-factor mechanism to "help mitigate unforeseen developments that necessarily are more likely to occur in the attrition period when a rate case cycle is extended another year."[50]

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[47] SCGC Comments at 1 and 2.

[48] TURN Comments at 2.

[49] TURN Reply Comments at 5. TURN clarifies that it is not offering an opinion on Staff's premise that the risks associated with an additional attrition year could be mitigated by (in Staff's words) "a uniform and consistent attrition year ratemaking mechanism that would factor in uncertainties during attrition years."

[50] SCE Comments at 2-3.

Movement to a four-year cycle is supported by PG&E, SDG&E and SoCalGas, and the Public Advocates Office. PG&E links its support to "appropriate attrition mechanisms and other mechanisms to adjust the revenue requirement during the GRC period – if needed – to address unusual circumstances." PG&E also notes the four-year cycle would provide the Commission with additional time to weigh "the extraordinary amount of evidence" presented in GRCs; to review additional financial data, including the data regarding the IOUs' expenditures in the filing year; allow an improved assessment of the IOUs' risks and risk-related spending, including possibly changing the timing of the RAMP allow for better integration into the IOUs' GRCs.[51] PG&E does acknowledge the concerns of Staff and other parties about adding a fourth year, but believes they can be addressed through an appropriate and uniform attrition mechanism, more flexibility regarding rate adjustments between GRCs, and existing memorandum accounts to address extraordinary circumstances and other anticipated expenses.[52] PG&E concludes by emphasizing its agreement with Staff that resolving the attrition issue and examining processes to request interim changes to the revenue requirement where appropriate could resolve some of the larger concerns that led Staff to recommend retaining a three-year cycle.[53]

SDG&E and SoCalGas reiterate their support for a four-year cycle. Here, they endorse further efforts to standardize attrition mechanisms. They also note

[51] PG&E Comments at 4-5.

[52] *Id.* at 5.

[53] *Id.* at 5-6.

that the RAMP phase adds a long lead time and this adds to resource constraints on all parties, including Commission staff, utilities, and intervenors.

Lastly, the Public Advocates Office has consistently advocated for a four-year cycle. As the party that conducts the most comprehensive quantitative analysis of GRC filings, their comments include a useful explanation of one challenge inherent in the three-year cycle:

> Test years of the initial case serve as base years for the following rate case. This presents a problem because recorded test year costs may not be representative of future costs, as utilities often initiate new programs during the test year, and these initial costs may not be representative of a more stable or steady-state level of expenses or expenditures. A 4-year GRC term allows for better utility financial and operational management of spending and investment.

The Public Advocates Office's comments also reference testimony by SDG&E and SoCalGas in their then-pending GRC applications, where both utilities proposed that the Commission authorize four-year GRC cycles (2019-2022). SDG&E noted that the GRC process has become more complex and subject to extended delays, which is now compounded by new processes, reviews, and reporting emerging from the S-MAP and RAMP proceedings.[54] SoCalGas echoed SDG&E, and added that a four-year GRC cycle would "reduce the administrative burden on all parties, and allow the utility to more effectively operate its business while implementing new risk-mitigation and accountability structures, processes and reporting requirements."[55]

While we acknowledge Staff's reasons for retaining the three-year cycle, we adopt a four-year cycle in this decision. As summarized above, we have

[54] Public Advocates Office Comments at 5-6, quoting SDG&E testimony in A.17-10-007.

[55] *Id.*, quoting SoCalGas testimony in A.17-10-008.

found parties' comments on both sides of this question to be very useful in deciding whether to move to a four-year GRC cycle. Based on our review, we find that a four-year cycle should improve the GRC process in two ways. First, the longer cycle will allow the utilities and stakeholders to dedicate more time to implementing the new risk-mitigation and accountability structures that this Commission established earlier in this rulemaking, and less time litigating GRC applications. Second, the longer cycle will enable the Commission and staff to shift their focus to monitoring utility spending in something closer to real-time, especially when the utility decides to re-prioritize authorized funding for another purpose.

The first of these expected improvements is the most compelling reason for this shift. It is important to enable the utilities to focus more on day-to-day operations within the framework for risk-mitigation and accountability that we established in D.14-12-025. We agree with parties' comments contending that the Commission's directives can be better implemented if the GRC cycle is longer. By lengthening the GRC cycle we can shift Commission resources to implementing the expanded utility reporting requirements. This will assist our oversight over utility risk management and safety spending, resulting in greater transparency and accountability of utility actions. We finalized this reporting framework earlier this year in D.19-04-020, our decision adopting risk spending accountability report requirements and safety performance metrics for PG&E, SCE, SDG&E and SoCalGas. That decision reviewed the first S-MAP applications filed by these utilities pursuant to D.14-12-025 and finalized the following reporting requirements in order to "allow Commission staff to more readily review and verify these safety-related activities, and to understand the reasons for the changes in priority that may have taken place."[56]

- PG&E, SCE, SDG&E and SoCalGas shall report annually on 26 safety performance metrics to measure achieved safety improvements.
- To improve understanding of the metrics, the reports shall include examples of how the metrics were used to improve safety training, take corrective action and support risk based decision-making.
- The reports shall include summaries of how reported data reflect progress against the risk mitigation and management goals approved in each utility's applicable RAMP filing and GRC application, and shall identify and provide additional information for any metrics that may be linked to financial incentives.
- Each utility shall file an annual Safety Performance Metrics report. The Commission's Safety and Enforcement Division (SED) staff will submit a review of each report.
- A standard format is established for the annual Risk Spending Accountability Reports (RSARs) by the utilities, which will report on deviations between approved and actual risk mitigation and maintenance spending and activities. A process for parties to comment on the RSARs is established.

In sum, then, the first advantage we see in moving to a four-year GRC cycle is that we expect this to facilitate the efforts of the Commission, its staff, and intervenors to use the mandated reporting to fulfill the intent expressed by the Commission in D.14-12-025:

> It is our intent that the adoption of these additional procedures will result in additional transparency and participation on how the safety risks for energy utilities are prioritized by the Commission and the

[56] D.14-12-025 at 46.

> energy utilities, and provide accountability for how these safety risks are managed, mitigated and minimized.[57]

The second improvement we expect from moving the four-year cycle is related to the first, but warrants separate discussion: a longer GRC cycle will facilitate the Commission's adjustment to an emerging reality of modern utility regulation, one that implies a fundamental change in the role of GRC proceedings. In earlier days, the theoretical and real-world purposes of a GRC were essentially the same: the Commission authorized the revenue requirement necessary to allow the utility to recover the reasonable costs of providing safe and reliable service, and to have an opportunity to earn a fair return on its investments. This focus on basic utility service was a workable approach during a time of less rapid technological change, relatively stable costs, and growing populations, and it needed only to be repeated on a periodic basis to maintain fairness for all stakeholders.

Over time, GRC proceedings at the Commission have become much less simple and straightforward. For example, in our review of the "regulatory compact" earlier in this decision, we noted that a utility's response to rapidly unfolding events that affect utility service, such as the catastrophic wildfires in 2007, 2017 and 2018, may require immediate re-prioritization of spending. Today, a significant portion of these re-prioritizations are reviewed in a utility's GRC, often long after the event. The Staff Report summarized workshop discussions of the relatively rapid developments in the electric utility industry in recent years, and the utilities, especially, described the challenges within the current GRC framework of bringing "emergent issues" with substantial revenue

[57] *Id*. at 2.

requirement implications to the Commission's attention in attrition years. Given our current GRC framework, this is a challenge regardless of the length of the GRC cycle.

In such circumstances, the importance of Commission oversight <u>in the midst of</u> the GRC period increases. It is no longer sufficient for the Commission to authorize a multi-year GRC revenue requirement for the utility, and then sit back and wait for the utility and intervenors to report back three years later regarding whether the utility spent the authorized amount, for the authorized purposes, or decided to use the funds elsewhere. We acknowledge that utilities may need to reprioritize spending between GRCs, and that in the evolving reality we describe above, that necessity may even be growing. However, we do not agree with PG&E's suggestion at the 2017 workshop that one of the necessities of moving to a four-year GRC cycle is "stakeholder agreement on the utility's need to reprioritize."[58] Similarly, SCE suggested that adding a fourth year "would assign to the Commission a greater tolerance for forecast error and acceptance of recorded expenses and [capital expenditures] that departed more markedly from authorized levels."[59]

Moving to a four-year cycle will enable the Commission to become more involved in monitoring how utilities reprioritize authorized GRC funding, not less. Accepting a four-year cycle and its attendant widening of "forecast error"

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[58] *See*, PG&E presentation at January 11, 2017 workshop, at 3. Available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452101

[59] SCE's presentation noted that because "the utility industry is going through significant change and there are many emergent issues, forecast error will be magnified and managing the 4th year with authorized revenue requirement may prove challenging." *See*, SCE presentation at January 11, 2017 workshop. Available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442462802

means that the Commission, the utilities and stakeholders will be able to spend less time in a GRC trying to achieve precision in forecasts, but dedicate more time and effort between GRCs to monitoring implementation of authorized revenue requirements. If the Commission is to accommodate the utilities' suggestions that a four-year cycle requires a more flexible regulatory approach, the utilities must reciprocate by more openly engaging in an ongoing dialog throughout the cycle that enables the Commission to review their activity in a transparent manner that ensures they are held accountable for how they spend ratepayer funds. Again, this will fulfill the Commission's intent that underlies the entire risk-mitigation framework adopted in D.14-12-025.[60]

Lastly, we note that supporters of the three-year cycle such as TURN and, especially, SCE did not rule out further examination of a four-year cycle, albeit on a slower timeline than we adopt in this decision. As we touched upon above, their comments and their earlier workshop presentations offer detailed and well-reasoned analyses of the forecasting, accounting and ratemaking mechanisms that, if implemented, would address many concerns about moving to a four-year cycle. For example, TURN's workshop presentation identified challenges such as (1) the added uncertainty inherent in forecasting capital spending for a third attrition year so far in advance; (2) exacerbating the overall risk of relying on outdated forecasts; and (3) the importance, at least initially, of reviewing the implementation of the safety and risk-related S-MAP and RAMP processes more often by retaining the three-year cycle.[61] As we have just explained, the improved monitoring tools provided by new reporting requirements should

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[60] *See*, D.14-12-025, Finding of Fact 27 and discussion at 10 and 43.

[61] *See*, TURN presentation at January 11, 2017 workshop, "Summary of TURN's Positions" at 3. Available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452102.

directly address the first two concerns listed by TURN. Regarding TURN's third point, the initial implementation of the S-MAP and RAMP processes are now mostly behind us, so we see less need to retain a three-year cycle to enable the more frequent review that TURN suggested at the workshop.

5.2. Combining PG&E's GT&S and GRC Proceedings

PG&E is unique among California's regulated utilities in that its revenue requirements for its gas transmission and storage systems are reviewed in a separate rate case, not part of its GRC. This framework dates back to 1997 when the Commission approved a settlement agreement between PG&E and numerous other parties, labeled the Gas Accord.[62] The settling parties described the Gas Accord as a "Proposal for a New Gas Market Structure for Northern California." As adopted, the Gas Accord set PG&E's gas transmission and storage rates through the end of 2002. The Commission subsequently approved similar settlements known as Gas Accords II, III, IV, and V, which carried the same approach to PG&E's gas transmission and storage rates forward through 2014. The first fully litigated GT&S rate case was A.13-12-012, which authorized revenue requirements and rates through 2018. Most recently, D.19-09-025 addressed the most recent PG&E GT&S rate case, adopting revenue requirements and rates through 2022.

The Staff Report recommends that PG&E's GT&S-related rate case requests and its GRC-related requests be submitted in a single application.[63] Staff acknowledges that a combined GT&S and GRC proceeding for PG&E would result in a "very large" filing, but contends that this would also provide the

[62] D.97-08-055, 73 CPUC 2d, 754.

[63] Staff Report at 29, Section 7.5.

Commission with a larger perspective on PG&E's company-wide operations and revenue requirement (with the exception of PG&E's FERC-regulated transmission system). Staff also recommends that the Commission ensure that additional staff and resources are dedicated to the combined proceeding.

PG&E supports this recommendation, but requests that the Commission also direct that GT&S rate design and revenue allocation issues be considered in a separate proceeding, not as part of the GT&S application as is the case today. TURN agrees, and suggests PG&E's periodic gas cost allocation and rate design proceedings as the appropriate forum, because they are similar to the electric GRC Phase 2 proceedings.[64]

We agree that the RCP should be modified to direct PG&E to file a single GRC application that incorporates its GT&S revenue requirement. This change shall be implemented as follows:

> Step 1: the Commission addressed PG&E's test year 2019 GT&S application (A.17-11-009) in D.19-09-025 and authorized revenue requirements for 2019-2021. The Commission also added a third attrition year, 2022, and determined that the next test year for PG&E's GT&S will be 2023.[65]
>
> Step 2: in PG&E's pending test year 2020 GRC application (A.18-12-008), PG&E seeks approval of revenue requirements for 2020-2022, so PG&E's next GRC test year will also be 2023.
>
> Step 3: PG&E should request initiation of its next RAMP proceeding in March 2020, and that filing should examine all the risks that are currently addressed separately in PG&E's GT&S and GRC proceedings.

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[64] TURN Comments at 2.

[65] D.19-09-025, Ordering Paragraphs 2 and 101.

Step 4: in 2021 PG&E shall file a single "general rate case" application requesting integrated GRC- and GT&S-related revenue requirements for test year 2023, and three attrition years.

Step 5: in 2022 PG&E shall, consistent with current practice, file a GRC phase 2 application addressing electric marginal costs, cost allocation and rate design. PG&E shall also file a gas cost allocation and rate design application that incorporates the GT&S-related rate design and revenue allocation issues previously considered in PG&E's GT&S application.

5.3. Moving the Due Date for the Public Advocates Office's Opening Testimony

The Staff Report recommends that the Commission modify the RCP schedule established in D.14-12-025 to move the due date for the Public Advocates Office's testimony from February 20th to "early April" of the year prior to the test year.[66] The Staff Report demonstrated that the February deadline is not realistic, because the Public Advocates Office simply cannot complete its comprehensive review of the utility application by that date. Staff agrees that a later date is needed to give the Public Advocates Office sufficient time to complete discovery and prepare its testimony.[67]

Other parties offer qualified support for an April due date. First, PG&E recommends that the Commission make an additional modification to the RCP so that the IOUs' approved revenue requirements become automatically effective on January 1st of the test year, regardless of when the Commission issues its final

[66] Staff Report at 24, Section 7.1.

[67] In its comments on the Staff Report, the Public Advocates Office notes that it actually requested a later due date in April, approximately mid-month, not the first of the month as Staff recommends. Public Advocates Office Comments at 3-4.

decision on the application.[68] Second, SCE emphasizes that a revised April deadline must be considered a firm date for receiving the Public Advocates Office's testimony, "rather than a new starting point from which [the Public Advocates Office] can readily seek additional extensions."[69] Third, SDG&E and SoCalGas recommend that if the Public Advocates Office's due date is moved to April 1st, then all intervenors should serve testimony no later than April 21 as Staff proposed: "[t]he Rate Case Plan should always attempt to conclude a GRC application before the Test Year begins."[70]

We agree that the RCP schedule adopted in D.14-12-025 should be modified to provide the Public Advocates Office with additional time to prepare and serve its testimony. The Public Advocates Office's testimony and recommendations are an indispensable element of all energy utility GRCs, which the Commission relies upon extensively as part of its own evaluation of a utility's requests. The Public Advocates Office is usually the only party that offers a complete alternative to the utility's requested revenue requirement, meaning that the Public Advocates Office runs the RO model based on its own recommendations and calculates its recommended revenue requirement in the same format as presented in the utility's application and testimony (*e.g.*, operation and maintenance expenses, depreciation expenses, tax expenses and return on ratebase). This provides the Commission with a fully realized alternative to consider. The other intervenors then have the Public Advocates

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[68] PG&E Comments at 6. Under current Commission practice, the utility must formally request this authorization, and the Commission addresses the request in a stand-alone decision early in the proceeding.

[69] SCE Comments at 3.

[70] SDG&E and SoCalGas Comments at 1.

Office's testimony as a point of reference as they prepare their own testimony, which is served approximately three weeks after the Public Advocates Office's testimony. The other intervenors typically lack the resources of the Public Advocates Office and generally cannot evaluate the entire utility request. Instead, they focus on specific issues and do not present an alternative total revenue requirement as the Public Advocates Office does. This more-focused intervenor testimony is no less helpful to the Commission, but our point here is that any changes to the RCP schedule should be supportive of the Public Advocates Office's task.

The revised RCP schedule we adopt in this decision provides the additional time the Public Advocates Office requests. We also agree that the Public Advocates Office should treat this date as a firm deadline that is unlikely to be extended in future GRC proceedings. Indeed, having granted the Public Advocates Office's request here, we do not expect they will seek extensions in future proceedings.

We do not adopt PG&E's request to modify the RCP to provide that a utility's GRC application shall automatically have an effective date of January 1 of the test year. Every GRC application has its own unique aspects, and we should maintain the flexibility to approve effective dates with consideration of whatever circumstances may present themselves during any particular GRC proceeding.

5.4. Adopted Revisions to Rate Case Plan

Having addressed the three recommendations in the Staff Report that directly affect the RCP schedule for future GRCs, we turn our attention back to the generic schedule we outlined earlier in this decision. That schedule demonstrated that we can satisfy the scheduling requests of the applicant utility, the Public Advocates Office, and the other intervenors if we move the filing date for the utility GRC application to March 1 of the year falling two years prior to the test year. Each of the three modifications we have just adopted will still work in that modified schedule. Therefore, in this decision we adopt the revised RCP schedule shown in Table 3 on the following page.

In this revised schedule, we note that we will require that each utility files its actual RAMP submission one year in advance of the GRC filing deadline, rather than simply sending its letter to the Commission's Executive Director on that date, requesting initiation of the RAMP OII. That two-step process consumes time that is needed for SED and parties to complete their review of the utility's RAMP more in advance of the subsequent GRC filing date, so that the utility has as much time as possible to meaningfully incorporate the results of this review in its GRC application.

Regarding timing, we note that the next utility scheduled to initiate its RAMP proceeding is PG&E, in 2020. We intend that our revised schedule apply to PG&E because we determined above that PG&E should combine its currently-separate GT&S rate case with its next GRC filing, and we do not wish to delay this for another GRC cycle. However, in order for PG&E to follow the revised schedule it would have to develop a RAMP that combines GT&S matters with GRC matters for the first time, and do so by March 1, 2020. If this is too soon for PG&E, the company should use its comments on the proposed decision to propose a workable modification to our revised schedule, specific to its 2020 RAMP filing and the subsequent filing in 2021 of its combined GRC/GT&S application.

Table 3
Adopted Revised GRC Application Filing Schedule
Effective January 1, 2020

Date	Day #	Event
Test Year minus-3		
January 1		Utility requests initiation of RAMP proceeding
February 15		RAMP Order Instituting Investigation (OII) is opened
March 1		Utility files its RAMP submission in the OII
Test Year minus-2		
March 1	Day 0	Utility files GRC application, and serves prepared testimony
By March 15	~Day 15	Utility holds public workshop on overall GRC application
30 days after Daily Calendar notice	~Day 30	Due date for protests and responses to GRC application, pursuant to Rule 2.6(a)
By April 15	~Day 45	Prehearing Conference held
By June 1	~Day 90	Scoping Memo of Assigned Commissioner issued (the target date is "Application + 90 days")
To be decided		Public Participation Hearings
By October 10	~Day 225	Public Advocates Office serves opening testimony
November 5	~Day 250	Intervenors serve opening testimony
December 20	~Day 295	Concurrent rebuttal testimony served
Test Year minus-1		
January 15	~Day 320	Evidentiary hearings begin
February 2	~Day 340	Evidentiary hearings end
To be decided		Update testimony and hearings, if necessary
March 10	~Day 375	Briefs filed
March 31	~Day 395	Reply briefs filed
August 1	~Day 520	Status conference, proceeding submitted for Commission decision [Rule 13.14(a)]
October 31	~Day 610	Proposed decision mailed for comment
November 30	~Day 640	Final decision adopted
Test Year		
January 1	~Day 670	Effective date of final decision

The revised schedule adds specific dates to areas labeled "to be determined" in the D.14-12-025 schedule, and also incorporates several simple schedule modifications proposed by parties that we agree will help GRCs proceed more efficiently. First, the "kick-off" workshop required of the applicant utility will take place within 2 weeks of the filing. Workshop participants appeared to agree that this workshop provides a useful and effective opportunity for the applicant to explain its application and respond to clarifying questions from parties. Second, the Prehearing Conference will be scheduled no later than two weeks after the due date for protests and responses to the GRC application. This should ensure that the Scoping Memo is issued in a timely manner as well.

We also note the revised schedule breaks the linkage between the submittal date and the date reply briefs are filed. Rule 13.14 (Submission and Reopening of Record), part (a) provides that "[a] proceeding shall stand submitted for decision by the Commission after the taking of evidence, the filing of briefs, and the presentation of oral argument as may have been prescribed." Pub. Util. Code § 311(d) requires that the proposed decision of the assigned ALJ or the assigned commissioner shall be issued not later than 90 days after the matter has been submitted for decision. Our recent experience indicates that 90 days is not enough time for the ALJs to draft a lengthy GRC proposed decision <u>and</u> to complete the RO modeling that calculates the resulting revenue requirement. Setting the submittal date several months after reply briefs are filed will allow the ALJ to begin drafting the PD upon receipt of briefs, but still leave a realistic period of time for the RO modeling. For this reason, the revised schedule includes a new milestone, a status conference that would take place approximately two months after filing of reply briefs. The status conference will provide an opportunity for the ALJ and the assigned Commissioner to obtain additional information that may assist in completion of the PD. Although the proceeding record would remain open until the status conference, protocols should be established at the outset of every proceeding to ensure that additional evidence would be taken at the status conference only under well-defined circumstances.

Table 4 on the following page provides a higher level summary of the transition from the current three-year cycle to the four-year cycle, including the scheduled filings for PG&E, SCE, SoCalGas, and SDG&E. We note that with the combination of PG&E's GT&S and GRC filings into a single application, the pattern of three utilities filing on a four-year cycle will result in no GRC being filed every fourth year.

Table 4
Summary of the Transition from the
Current Three-Year Cycle to the Four-Year Cycle

	Pending Applications: 3-year cycle				4-Year Cycle: First Round				4-Year Cycle: Second Round			
	PG&E--GT&S	PG&E	SCE	SDG&E and SoCalGas	PG&E	SCE	SDG&E and SoCalGas		PG&E	SCE	SDG&E and SoCalGas	
Test Year ==>	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2017		RAMP										
2018		GRC	RAMP									
2019	Test Year		GRC	RAMP								
2020	PTY-1	Test Year		GRC	RAMP							
2021	PTY-2	PTY-1	Test Year		GRC	RAMP						
2022	3rd PTY	PTY-2	PTY-1	Test Year		GRC	RAMP					
2023			PTY-2	PTY-1	Test Year		GRC					
2024				PTY-2	PTY-1	Test Year			RAMP			
2025					PTY-2	PTY-1	Test Year		GRC	RAMP		
2026					PTY-3	PTY-2	PTY-1			GRC	RAMP	
2027						PTY-3	PTY-2		Test Year		GRC	
2028							PTY-3		PTY-1	Test Year		
2029									PTY-2	PTY-1	Test Year	
2030									PTY-3	PTY-2	PTY-1	
2031										PTY-3	PTY-2	
2032											PTY-3	

Notes:

1. PG&E's 2019-2021 GT&S revenue requirement adds a 2022 attrition year
2. No GRCs will be filed in 2026, 2030 and every fourth year onward

5.5. Additional Workshops

In addition to the specific recommended modifications to the RCP that we addressed above, the Staff Report also recommends that the Commission direct the Energy Division to host additional workshops to further examine a number of ideas raised by workshop participants regarding how to further standardize GRC filings and streamline the GRC process.[71] The Staff's recommendations for workshops and schedules are summarized below:

	Energy Division Staff-Recommended Workshops	Proposed Scheduling
1	Standardizing GRC filings	3 months after this decision is issued
2	RO model uniformity	6 months after Workshop #1
3	Stipulated terms or rebuttable presumptions	6 months after Workshop #2
4	FERC accounting	To be determined

Each of the parties that addressed Staff's recommendations supported the general idea of more workshops, though not necessarily the specifics.[72] SCE offers useful suggestions regarding advance preparations by the Energy Division to ensure that the workshops are efficient uses of parties' time and result in recommendations that are helpful to the Commission. SCE suggests that ED meet "off-line" with each of the stakeholders prior to preparing workshop agendas, and circulating initial substantive proposals for review and comment in advance of each workshop.[73]

We appreciate the willingness of parties to continue to work together to improve GRC proceedings. We also agree with SCE's general recommendation

[71] Staff Report at 25, Section 7.2.

[72] PG&E Comments at 9; SCE Reply Comments at 2; SDG&E and SoCalGas Comments at 1; TURN Comments at 2.

[73] SCE Reply Comments at 2.

that the workshop process be structured in a way that makes good use of stakeholders' time and leads to further efficiencies and improvements in GRCs. Parties also offered thoughtful analysis of the detailed workshop proposals in the Staff Report, agreeing with some and opposing others. Our discussion below benefits from that analysis. As will be seen, our adopted plan for further workshops will address fewer issues than recommended by Staff, and do so in a somewhat shorter period of time.

5.5.1. Should a Future Workshop Address Standardizing GRC Filings?

Staff suggests in the workshop report that if each of the energy utilities followed uniform filing standards when preparing their applications, the Commission could process the applications more efficiently, and would also find it easier to directly compare revenue requirements across utilities. Staff also envisions that standardized filings would reduce the need for staff to develop utility-specific expertise. For these reasons, the Staff Report recommends that a workshop be held to address the topic of standardizing GRC filings, with a focus on four sub-topics:

1. Data Request Format: development of a standard process and format for all data requests sent to the utility, whether originated by intervenors or Commission staff [Master Data Request]
2. Joint Comparison Exhibit (JCE): development of a standard process and format to be used by all utilities, for use by the Commission in reviewing issues in the proceeding
3. Standard Index for Testimony: discussion of whether the utilities and other parties should prepare testimony using standardized chapter numbers that always reference the same class of expenses.
4. The Base Year and Requirements Regarding Recorded Data: stakeholders would explore whether the Commission should change the base year of a GRC, and how the Commission can

formally include the recorded spending data from the year of filing into the records of the GRC proceedings.[74]

5.5.1.1. Data Request Format

SCE supports adopting a form of Master Data Request that would be useful to the Staff from different Commission divisions. In addition to the workshop-type exploration that Energy Division recommends, SCE suggests that each utility host a meeting with Commission Staff and GRC parties before the utility files its GRC application. At such meetings, the utility could gather and synthesize similar inquiries from parties and staff, and thereby provide more comprehensive responses on a more efficient basis.[75]

SDG&E and SoCalGas agree that the Master Data Request used in GRC proceedings should be standardized to the extent possible.[76]

We agree that stakeholders should develop and utilize a standard data request format, and this is a good example of a matter that would benefit from "off-line" development prior to any workshop, as SCE recommended in its reply comments. We do note some confusion in terms regarding whether this recommendation relates (1) solely to the so-called "master data request" that is sometimes a feature of utility applications and is filed at the same time as the application and testimony, or (2) to all discovery requests in a GRC proceeding, from intervenors to the applicant, and vice versa. We prefer that parties reach

[74] The Staff Report explains at 10 (footnote 15): "[w]hen a utility files a GRC, the utility needs to include recorded spending data from the most recent year in its filing to justify the forecasted costs in the test year. This year of recorded spending data is called the base year." With a three-year GRC cycle, the base year of recorded data for a future GRC filing is the test year of the last GRC filing.

[75] SCE Comments at 9.

[76] SDG&E and SoCalGas Comments at 2.

agreement on the broadest scope and the most standardization that can be reasonably achieved. From the Commission's standpoint, especially when discovery disputes arise or an "off-line" dispute is referenced by parties during hearings, it is important to be able to clearly and consistently determine the following information at a glance, rather than spend time in hearings doing so:

- The party and witness that originated the data request;
- The date of the data request, and the requested response date;
- The actual response date, including whether any extensions were negotiated and, if so, when and by whom; and
- The name of the witness sponsoring the response.

Finally, workshop discussions about master data requests should include their use in each utility's RAMP proceeding. For example, if SED's review of the RAMP filing could benefit from use of a standardized and obligatory master data request, the format and questions should be developed at the future workshop or workshops discussed later in this decision.

5.5.1.2. Standardized Joint Comparison Exhibit

SCE supports exploration of adopting a standardized form of the JCE, where parties would continue to contribute to the JCE by providing their specific inputs into the JCE, which is then compiled by the applicant utility.[77] SDG&E and SoCalGas agree that the JCEs used in GRC proceedings should be standardized to the extent possible.[78]

We note that JCEs are not prepared in every GRC; rather, its necessity is discussed and resolved by the assigned Commissioner, ALJ, and the parties. We see value in devoting workshop time to reaching agreement on a standard

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[77] SCE Comments at 9.

[78] SDG&E and SoCalGas Comments at 2.

format because this would help the assigned Commissioner and ALJ decide early in the proceeding whether to require parties to prepare a JCE at all. We also note that in past GRCs the JCEs that were useful to us as we made our decisions were those that clearly show the differences between parties, especially in summary form, while also providing specific citations to testimony for those reviewers needing or wanting to delve deeper into the details of parties' positions. We also direct parties to discuss the feasibility of preparing, prior to evidentiary hearings, a summary of positions on contested issues in order to provide the assigned Commissioner and ALJ with a "roadmap" to assist in efficiently conducting the hearings.

5.5.1.3. Standard Index for Testimony

Parties did not address this recommendation in their comments, but we agree that a standardized index would be helpful and should be developed prior to, and finalized during, the workshops we endorse in this decision. In every GRC, the Commission's essential task is identical: to authorize the level of funding necessary for the applicant utility to provide safe and reliable service at just and reasonable rates. However, each GRC that comes before the Commission is likely to be overseen by different assigned Commissioners and ALJs, so a standardized presentation of each applicant's request will assist the Commission as a whole to understand the issues in any given GRC.

Given the importance to the energy utilities of having an approved revenue requirement prior to the beginning of the test year, it is in their self-interest to make it as easy as possible for every Commissioner, not just the assigned Commissioner who is most familiar with the proceeding, to evaluate the requests of any utility in any GRC. By presenting their testimony according to a common outline, and using consistent terminology and standard table formats, the utilities will ease the work of the Commission.

Standardization should also be extended to the utilities' RAMP filings, which will assist SED and parties in their review. A standard format should be developed for mapping RAMP risk mitigations to GRC testimony and workpapers. GRC workpapers should also indicate which costs are RAMP-related costs, and which are non-RAMP-related. We include these topics in our list of workshop topics at the end of this decision.

5.5.1.4. The Base Year and Requirements Regarding Recorded Data

SDG&E and SoCalGas agree that use of base year recorded data in GRCs should be addressed to determine where it might be practical to standardize. However, they also note that "while utilities can provide the recorded data, it would not be efficient to retrofit back to workpapers and models, nor provide 'updated' spreadsheets with the Base Year +1 data."[79]

Agreement on a standard approach to "Base Year +1 data" should be an important topic for future workshops. Stakeholders should endeavor to reach consensus on a means of incorporating this data into every GRC on an agreed-upon schedule. For example, in the recently concluded SCE 2018 test year GRC, the base year was 2015. However, during the proceeding SCE was able to update its recorded spending data in its June 2017 rebuttal testimony to include all of 2016 (i.e., "Base Year +1). It is neither surprising nor alarming that the recorded 2016 data was often very different from the corresponding 2016 forecasts included in SCE's September 2016 application. The Commission's decision-making benefited from having the recorded 2016 data available because

[79] *Ibid.*

of the improved accuracy, so that should be considered a standard milestone in every energy GRC.

5.5.2. Should a Future Workshop Address Stipulated Terms, Rebuttable Presumptions, and Formula-Based Attrition Year Revenue Requirements?

The Staff Report explains that some parties at the workshop proposed that the Commission could process GRC applications more quickly if it considered adopting stipulated terms, such as using multi-year averages of historical spending for certain common or predictable expenses, or rebuttable presumptions for certain "base operation" expenses:

> In its presentation, SCE suggested that the Commission adopt stipulated terms for certain "base operation" expenses, particularly expenses for activities that can be forecasted using multi-year averages. During discussions, TURN also suggested that the Commission adopt certain expenses under rebuttable presumptions to reduce the amount of litigated issues in a GRC. For example, the Commission could employ a rebuttable presumption that base year plus inflation is adequate for general operational, maintenance, and administrative expenses that are not funding new programs.[80]

The Public Advocates Office expressed more caution regarding these suggestions. The Staff Report suggests that a workshop examine whether the Commission can adopt stipulated terms or rebuttable presumptions without compromising its ability to determine whether the funding requests are just and reasonable. The workshop could consider not just whether the Commission could adopt certain test year expenses under stipulated terms or rebuttable

[80] Staff Report at 19. To ensure parties have a common understanding of this proposal, we provide the following definition of a rebuttable presumption: "a presumption which is not conclusive but may be overcome by opposing evidence." Accessed online at Ballentine's Law Dictionary, LexisNexis, July 11, 2019.

presumptions, but also whether attrition year revenue requirements could be determined based upon rebuttable presumptions such as a standard escalation formula, or "an incentive ratemaking mechanism for the attrition years based on the utility's return on equity or return on rate base."[81]

In its comments, SCE agrees that workshops are warranted "to ascertain if the Commission can adopt stipulated expenses, or rely upon rebuttable presumptions" to help streamline the processing of GRCs.[82] SDG&E and SoCalGas generally agree as well, while noting that "there are already procedures for stipulations, and areas parties typically can stipulate are often non-controversial."[83] SDG&E and SoCalGas also indicate that they require more details about how rebuttable presumptions and incentive ratemaking for attrition years might add value or be pursued in the GRC context.[84]

TURN encourages the Commission to expedite the consideration of these topics in a workshop: "[g]iven the work already done by staff and parties to identify these potential GRC policy changes to streamline the processing of GRCs (where feasible), TURN submits that it would be a shame to delay the benefits…" of reduced litigation in GRCs and more efficient GRC proceedings.

We agree with TURN that a workshop should be held relatively quickly to further refine the recommendations at the 2017 workshop and in the 2018 Staff Report regarding approaches that could reduce the number of litigated issues. To our mind, this topic differs somewhat from the stipulations referenced by SDG&E and SoCalGas, which are common in GRCs but also unique to an issue

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[81] Staff Report at 20 and 26.

[82] SCE Comments at 7.

[83] SDG&E and SoCalGas Comments at 2.

[84] *Ibid.*

or a stakeholder's interest in that particular proceeding. Instead, the workshops directed in this decision should focus on building a framework for the utility's initial showing that rests upon stipulated approaches to escalating capital expenditures or operating expenses, or rebuttable presumptions about the same test year operating expense forecasts. This framework could become common to every GRC, for every utility.

Regarding the matter of formula-based attrition year revenue requirements, this is already the typical approach to the operating expense portion of the revenue requirement, which is determined by applying a range of escalation factors to specific expense categories within the adopted test year forecast. Greater efficiencies in this area would clearly result if agreed-upon stipulations or rebuttable presumptions were in place at the outset of a proceeding. We are more cautious about implementing such an approach to the capital expenditure portion of attrition year revenue requirements. We do not intend to adopt an approach that places such increases on "autopilot" for three years out of every four-year GRC cycle—the long-term impact of capital investments on customer rates warrants a closer look at the attrition year changes and ongoing monitoring by Commission staff via the reporting requirements introduced by D.14-12-025, especially at a time when the utilities seek "stakeholder agreement on the utility's need to reprioritize" as PG&E suggested at the 2017 workshop.

5.5.3. Should a Future Workshop Consider Greater Uniformity in the Results of Operation Model?

The Staff Report recommends that a future workshop explore ways to make the RO models of the four utilities more uniform and user-friendly, including the following (ranked from easiest to most difficult):

1. Developing a standard format for the Summary of Earnings table, which is usually a single table that shows the major components of the applicant's requested revenue requirement, and at the end of the proceeding, the amounts authorized by the Commission (e.g., operating expenses, depreciation expenses, tax expenses, and return on rate base);
2. Developing a user-friendly input interface for the RO model, to enable a user without extensive RO modeling training to enter inputs into the model to calculate the revenue requirement; and
3. Developing a uniform RO model format or structure so that they would be more consistent across the utilities and, presumably, easier for the Commission and others outside the utilities to understand.

The utilities' comments in response to these recommendations note that the first item listed above would be simple to develop, while the second would be more difficult and of questionable value to our effort to streamline GRC proceedings, and the third item would be "extremely challenging"[85] and (in our own view) not justified by the effort involved.

The Commission relies on RO models for purposes that lead us to suggest that a different list of refinements could be undertaken in order to help the Commission issue GRC decisions more quickly. First, our overarching concern is that the RO results and revenue requirement that is included in the ALJ's proposed decision is accurate. It is also important that parties trust that the calculation is accurate, no matter who does that calculation. Furthermore, given the time pressures at the end of GRC proceedings it is very important that the actual task of preparing the RO calculations proceeds smoothly. As has been typical in recent years, we have no problem relying on the utilities to prepare the

[85] PG&E Comments at 9.

RO for the PD and the final Commission decision, albeit with Energy Division oversight and a non-disclosure agreement in place. The utilities know their own models best, which ensures as accurate a calculation as possible, and the penalties they would incur for violating our trust and manipulating the results far outweigh any potential gain. However, the "typical" process could be improved in a way that would result in more timely GRC decisions. In future GRCs, under Energy Division oversight and non-disclosure agreement, each utility should begin working with the Energy Division as soon as possible in the drafting process and incorporate the ALJ's determinations as they are made instead of waiting for a completed written draft of the entire proposed decision before beginning the RO work. The future workshops would provide an opportunity for the utilities to explain their perspectives and develop a single approach to their working relationship with the ALJ and Energy Division staff, to be used by all utilities in all GRCs going forward. This would introduce greater predictability to this aspect of preparing the PD.

Furthermore, as noted above, in most large energy GRCs the Public Advocates Office is the only party that performs RO modeling independently of the utility applicant. We hope this practice continues. The Public Advocates Office can make its own needs clear in the upcoming workshops, but we indicate here that we prefer that any reasonable needs expressed by the Public Advocates Office are heeded and accommodated by the utilities. For example, if the Public Advocates Office believes the RO models are becoming too complex, the utilities should pay close attention to their recommended solutions. Similarly, if *any* intervenors can demonstrate the value of greater standardization at either the "input" stage or the "output" stage than we have endorsed here, the utilities should consider those recommendations. Any refinements that ease the burden on GRC parties are likely to translate into greater efficiencies for the Commission's decision-making as well.

Our final item regarding the RO model is one that was not mentioned in the Staff Report or parties' comments: bill impacts. Each utility currently includes summary-level bill impacts for a residential customer in its GRC application, but only for one "average" usage level, and without differentiating by usage in various climate zones, or other means, in the utility's service territory.[86] The Energy Division should include the task of incorporating standardized bill impact calculations into every GRC application as a mandatory topic at the future workshop(s). The utilities should consider this to be a compliance item imposed on each of them by this decision.

5.5.4. Should a Future Workshop Address FERC Accounting?

The fourth and final workshop recommended in the Staff Report would further explore the benefits and costs of requiring the utilities to present their GRC requests in a format that conforms to the corresponding FERC accounting structure.[87] Staff explains that requiring utilities to present their GRC in this

[86] *See*, for example, A.18-12-009, PG&E's application for authority to increase rates and charges for electric and gas service effective on January 1, 2020, at 5, Table 2, "Impact on Non-CARE Residential Typical Customer Bills."

[87] As the FERC explains on its website, it is "responsible for the accounting and financial reporting of its jurisdictional companies. This is accomplished through the development and maintenance of the Commission's Uniform System of Accounts" which "provides basic account descriptions, instructions, and accounting definitions" that the FERC describes as useful in understanding the information reported in electric utilities' annual reports to the FERC, which are commonly known at the "FERC Form 1."
https://www.ferc.gov/enforcement/acct-matts/usofa.asp

In turn, the FERC describes its Form 1 as "a comprehensive financial and operating report submitted annually for electric rate regulation, market oversight analysis, and financial audits by major electric utilities." https://www.ferc.gov/docs-filing/forms.asp?new=sc1#1

Footnote continued on next page

manner would enable the Commission and parties to more easily compare costs across the four utilities, as well as to utilities across the country that are also required to report this data in annual FERC Form 1 and Form 2 filings.

The Staff Report acknowledges that workshop participants expressed widely different opinions about whether the Commission should adopt this requirement. Staff suggests the recommended workshop would provide an opportunity to address this question in greater depth.

As Staff anticipated, the utilities uniformly oppose the idea of presenting their GRC applications using the FERC Uniform System of Accounts, or even scheduling a workshop to discuss the idea further. SDG&E and SoCalGas explain succinctly what PG&E and SCE state in greater detail: "[a]lthough standardization of accounting systems across all utilities for GRC purposes might seem to be a desirable goal, use of the FERC system of accounts would not be feasible or realistic, as all the utilities are very different."[88]

The utilities have convinced us that requiring them to present their GRC requests in a format based on FERC accounts would be inadvisable and would not result in greater efficiencies or streamlining of the GRC process. That said, one takeaway for the utilities from our discussions above should be the importance we place on having information available to us that allows us to compare the utilities with each other on an "apples-to-apples" basis. If the FERC accounting framework is not the best means of accomplishing this goal, we expect the utilities to suggest a better approach. Once again, though it may not

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Our record is unclear regarding whether the FERC requires similar standardized accounting by natural gas distribution companies.

[88] SDG&E and SoCalGas joint Comments at 3. *See also* PG&E Comments at 9-10 and SCE Comments at 6-7.

seem so to the utilities, our review of any particular GRC application can be completed more quickly if all the applications are presented to us in a common format.

5.5.5. Adopted Workshop Topics and Schedule

As we said earlier in this decision, we embrace any changes to the RCP that will help us process GRCs more efficiently. The same goes for future workshops. Parties' comments on the Staff Report have helped us narrow the list of topics that should be considered in workshops to those where parties indicated success is likely. On that basis, we direct Staff to schedule one or more workshops to address the topics listed below. We leave it up to Staff, working collaboratively with parties at the planning stage as SCE suggests in its comments, to organize the details.

We would welcome parties' suggestions for improvements in the following broad areas:

1. Standardizing the organization and format of GRC and RAMP filings and the proceeding record, including the possibilities offered in the Staff Report:
    a. Developing and recommending a standard index for testimony;
    b. Developing and recommending a standard format for mapping RAMP risk mitigations to GRC testimony and workpapers. GRC workpapers should also indicate which costs are RAMP-related costs, and which are non-RAMP-related;
    c. Developing and recommending a standard data request format, including for the RAMP, as we discussed in Section 5.5.1 above;
    d. Developing and recommending a standard format for the Joint Comparison Exhibit; and

e. Developing and recommending general ground rules regarding identification of the Base Year, as well as a common framework for incorporating updated "Base Year +1" recorded data at a given stage of the GRC proceeding.

2. Discussing and developing recommendations regarding the possible use of stipulated terms, rebuttable presumptions, and escalation-based attrition year revenue requirements. We clarify here that we do not consider these workshops to be the proper forum for more far-reaching discussions regarding an incentive ratemaking mechanism for attrition years, so Staff should not pursue that idea further in these workshops.

3. Results of Operations

   a. Developing a standard format for the "Summary of Earnings" table produced by the RO model to be incorporated into each utility's RO model;

   b. To more efficiently complete the RO modeling for the proposed decision, developing a single approach across utilities to the working relationship with the ALJ and Energy Division staff; and

   c. Developing and incorporating standardized bill impact calculations into every GRC application.

Finally, regarding scheduling, we agree with TURN's observation that Staff's proposal to divide these topics between several workshops spread out over many months may be too gradual, in light of the progress already made by Staff and the parties to identify potential policy changes to streamline the processing of GRCs. Having taken several larger topics off the table, we leave it to Staff and interested parties to decide the best way to address the topics we list above, while relying on pre-planning as suggested by SCE to focus activity at the workshop(s) on finalizing parties' proposals and recommendations.

5.6. Should the Commission Open a "Tax Rulemaking"?

The Staff Report includes a recommendation that the Commission open a new rulemaking to revisit its policies on the utilities' recovery of income tax expenses and related rate base issues.[89] Staff explains that in recent energy GRCs a number of issues pertaining to income tax expenses were heavily contested and litigated. Furthermore, Staff suggests that the Commission's policies on taxes may not have kept pace with recent changes in the tax law. Staff concludes that "a look at the Commission's policies on the utilities' recovery of income tax expenses is long overdue" and recommends that the Commission open a new rulemaking in order to adopt a consistent tax policy for all the energy utilities.

Parties' comments on this recommendation ranged from tentative support to outright opposition. SDG&E and SoCalGas would support a "properly scoped" rulemaking.[90] TURN, while it "would not oppose" such a rulemaking, notes that it would be difficult to effectively participate in the "foreseeable future" because of the demands of other Commission matters, such as GRCs, wildfire-related applications, rate design-related dockets, resource planning and procurement proceedings, among others.[91] SCE suggests the Commission consider this to be a "lower-priority issue" as it reviews the Energy Division's recommendations.[92] Finally, PG&E does not agree that a separate rulemaking on taxes is necessary, given the balancing and memorandum accounts that have already been adopted for the utilities to address tax changes as well as the

[89] Staff Report at 27, Section 7.3.

[90] SDG&E and SoCalGas Comments at 3.

[91] TURN Comments at 3.

[92] SCE Comments at 5.

processes currently underway to adjust the IOUs' revenue requirements to reflect recent changes to the Internal Revenue Code resulting from the Tax Cuts and Jobs Acts of 2017 (TCJA).[93]

Based on these comments, we find that it is not necessary to open a new rulemaking to address tax issues. In GRC decisions issued more recently than the Staff Report, the Commission directed each of the energy utilities to establish Tax Memorandum Accounts with a common structure.[94] Our intent in doing so was to address the types of concerns raised by the Energy Division in the Staff Report. And as noted by PG&E, following passage of the TCJA we directed each utility subject to our jurisdiction (including all energy utilities) to take certain actions to pass any tax savings that resulted from the new legislation immediately on to ratepayers. In short, we are comfortable that the Commission and its staff are now equipped to monitor changes in the tax law and quickly exercise our oversight over the utilities in order to ensure that ratepayers are treated fairly as new provisions are implemented.

5.7. Closure of this Rulemaking

The Staff Report recommends that the Commission close R.13-11-006 and open a new rulemaking to implement the recommendations adopted in this decision. As we explained at the outset of this decision, the Commission opened this rulemaking primarily to develop and adopt a risk-based decision-making framework to evaluate safety and reliability improvements in the rate cases of the energy utilities. The Commission completed that task when it adopted D.14-12-025, but left this proceeding open in order to provide a forum for the

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[93] PG&E Comments at 2 and 8-9.

[94] *See*, for SDG&E and SoCalGas, D.16-06-054, Ordering Paragraph (OP) 4; for PG&E, D.17-05-013, OP 11; and for SCE, D.19-05-020, OP 5.

issues that we resolve in this decision. Today's decision addresses all of the tasks within the scope of R.13-11-006. While we do expect that the workshops we endorse in this decision will yield additional "actionable" recommendations to improve our GRC process, we will treat parties' obligations to provide those recommendations as "compliance items." By doing so, we can close this rulemaking with the issuance of this decision, while preserving the option to either reopen this proceeding or initiate a new rulemaking, depending on the recommendations ultimately provided by parties.

6. Comments on Proposed Decision

The proposed decision of Commissioner Rechtschaffen in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _______, and reply comments were filed on __________ by __________.

7. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner and Stephen C. Roscow is the assigned ALJ in this proceeding.

Findings of Fact

1. The Commission follows a RCP to govern the information, processes, and schedule associated with the GRC applications of the energy utilities.

2. In order to adopt and develop a risk-based decision-making framework to evaluate safety and reliability improvements, D.14-12-025 modified the schedule of the RCP previously followed by the energy utilities pursuant to Appendix A of D.07-07-004.

3. Modifying the RCP to add a third attrition year and create a four-year GRC cycle without making other changes to the RCP schedule would not lead to more efficiencies.

4. Pursuant to Ordering Paragraph 101 of D.19-09-025, unless otherwise directed by the Commission, PG&E shall file its next GT&S rate case consistent with the schedule required for a 2023 test year.

5. The Commission would gain a total-company perspective on PG&E's cost of service, including risk-related spending, if PG&E's GT&S- and GRC-related revenue requirements were reviewed in a single general rate case.

6. The amount of time presently allowed in the RCP for the Public Advocates Office to complete discovery and prepare its testimony is inadequate.

7. If the GRC proceedings began in March instead of September, the schedule would enable the Commission to issue its final decision prior to the utility applicant's test year.

8. Additional workshops could explore standardizing the organization and format of GRC and RAMP filings; the possible use of stipulated terms and rebuttable presumptions to reduce litigated issues, and improving the accuracy of attrition year forecasting, escalation factors, and ratemaking; and high level consistency in the Results of Operations modeling process across utilities.

9. There is no need to conduct workshops to produce complete uniformity in the results of operation model, or to consider the use of the FERC's Uniform System of Accounts in the utilities' GRC applications.

10. There is no need for the Commission to open a rulemaking on GRC-related tax issues because in recent GRC decisions the Commission has directed each of the energy utilities to establish Tax Memorandum Accounts with a common structure. This will enable the Commission to monitor changes in the tax law

and quickly exercise its oversight over the utilities in order to ensure that ratepayers are treated fairly as new provisions are implemented.

Conclusions of Law

1. The end goal of this rulemaking is to revise the RCP to better facilitate utility revenue requirement showings based on a risk-informed decision-making process that will lead to safe and reliable service levels that are in compliance with state and federal guidelines, rational, well-informed and comparable to the best industry practices, and that the adopted rates are just and reasonable.

2. The RCP should be modified if it will enable GRC proceedings to be conducted more efficiently.

3. No evidentiary hearings are needed in this proceeding because this is a quasi-legislative proceeding which establishes policy, and the Commission can consider and base its policy determinations on the pleadings and comment process which has been filed in this proceeding.

4. The RCP should be revised to require that the GRCs of PG&E, SCE, SoCalGas and SDG&E follow a four-year cycle based on a forecast test year revenue requirement, followed by three attrition years.

5. PG&E's GT&S- and GRC-related revenue requirements should be reviewed in a single general rate case.

6. The GRC RCP schedule shown in Appendix A to this decision should modify and replace the RCP schedule adopted by the Commission as shown in Table 4 of D.14-12-025 and should take effect on March 1, 2020.

7. The inclusion of bill impacts for residential customer in utility GRC applications, differentiated by usage in each climate zone, or other means, in the applicant's service territory, would help the Commission determine whether its decision on the application will result in just and reasonable rates.

8. The Commission's Energy Division should facilitate a workshop or workshops within six months of today's date, and subsequent workshops as needed, to address the topics listed in Section 5.5.5 of this decision, "Adopted Workshop Topics and Schedule."

9. The Commission should not open a new rulemaking to address tax issues.

O R D E R

IT IS ORDERED that:

1. Table 1 in Appendix A to this decision modifies and replaces the "GRC Application Filing Schedule" presented in Table 4 of Decision 14-12-025.

2. Beginning March 1, 2020 the "GRC Application Filing Schedule" presented in Table 1 in Appendix A to this decision shall apply to all future General Rate Case application filings of Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas & Electric Company.

3. Pursuant to Ordering Paragraph 101 of Decision 19-09-025, Pacific Gas and Electric Company is directed to incorporate its requests for test year 2023 revenue requirements related to its gas transmission and storage systems into its test year 2023 general rate case application.

4. The Commission's Energy Division shall facilitate a workshop or workshops within six months of today's date to address the topics listed in Section 5.5.5 of this decision, "Adopted Workshop Topics and Schedule." No later than 30 days after the conclusion of the workshop or workshops, a designated utility shall submit a report summarizing the workshop or workshops and any agreed-upon proposals, as a compliance item in this docket.

5. As a compliance item in this docket, Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, and

San Diego Gas & Electric Company shall develop bill impact calculations for residential customers in the applicant's service territory, differentiated by usage in each climate zone, or other means as may be directed by the Commission or by the Director of the Energy Division, to be included in every future GRC application. The utilities shall present their standardized calculations for discussion at the workshop or workshops facilitated by the Energy Division pursuant to Ordering Paragraph 4 of this decision.

6. Rulemaking 13-11-006 is closed.

This order is effective today.

Dated _____________________________, at San Francisco, California.

APPENDIX A

Table 1
Adopted Revised GRC Application Filing Schedule
Effective January 1, 2020

Date	Days	Event
Test Year minus-3		
January 1		Utility requests initiation of RAMP proceeding
February 15		RAMP Order Instituting Investigation (OII) is opened
March 1		Utility files its RAMP submission in the OII
Test Year minus-2		
March 1	Day 0	Utility files GRC application, and serves prepared testimony
By March 15	~Day 15	Utility holds public workshop on overall GRC application
30 days after Daily Calendar notice	~Day 30	Due date for protests and responses to GRC application, pursuant to Rule 2.6(a)
By April 15	~Day 45	Prehearing Conference held
By June 1	~Day 90	Scoping Memo of Assigned Commissioner issued (the internal ALJ deadline is "Application + 90 days")
To be decided		Public Participation Hearings
By October 10	~Day 225	Public Advocates Office serves opening testimony
November 5	~Day 250	Intervenors serve opening testimony
December 20	~Day 295	Concurrent rebuttal testimony served
Test Year minus-1		
January 15	~Day 320	Evidentiary hearings begin
February 2	~Day 340	Evidentiary hearings end
To be decided		Update testimony and hearings, if necessary
March 10	~Day 375	Briefs filed
March 31	~Day 395	Reply briefs filed
August 1	~Day 520	Status conference, proceeding submitted for Commission decision [Rule 13.14(a)]
October 31	~Day 610	Proposed decision mailed for comment
November 30	~Day 640	Final decision adopted
Test Year		
January 1	~Day 670	Effective date of final decision

(END OF APPENDIX A)